Standby Service Rate Design Issues
A Whitepaper by NHPUC Staff

Background

In an order[1] issued September 2, 2004 in Docket No. DE 03-200, the Commission responded to a request by PSNH to revise all of its general service rate schedules plus Backup Delivery Service Rate B. Rate B is the rate PSNH charges for standby service to onsite generators that are connected to and operate in parallel with its delivery system.[2] Although the Commission accepted the Revenue Requirements and Rate Design settlements proposed by the settling parties[3] in that docket, it nonetheless determined that the public interest would be advanced by the preparation of a whitepaper on the design of standby electricity rates and the opening of formal proceedings, if necessary, to change the design of Rate B. This whitepaper is the result of that directive.

Although the goal of this paper is to facilitate a broad discussion of standby service rate design, we also address many of the issues raised by non-settling parties such as Wausau. It is our hope that the views expressed in this whitepaper will be helpful to all those who use standby services or are considering installing onsite generation, whether for backup, maintenance, or supplemental purposes, but in particular the parties that participated in Docket

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[1] Order No. 24,369.

[2] Standby service is the generic term used in the industry for service to a customer who has installed onsite generation to serve his or her own load but the generator is temporarily unavailable.

[3] The settling parties are Public Service Company of New Hampshire, Florida Power and Light Company, FPL Energy Seabrook, LLC, FPL Energy Maine Hydro, LLC, Pinetree Power Inc., Pinetree Power-Tamworth, Inc., Bridgewater Power Company, LP, Hemphill Power & Light Company, Ski NH, the Office of Consumer Advocate, and the Commission Staff.

DE 03-200. Standby service customers typically include self-generation, cogeneration and qualifying facilities interconnected to utility transmission or distribution systems.

The whitepaper is organized into twelve sections. The first includes the background to the Commission's decision to issue a whitepaper. The second section includes a general definition of standby service and discusses the different service types. The principles of utility ratemaking are briefly addressed in section three. PSNH's standby rate design is discussed in section four, and is followed in section five by a discussion of whether the characteristics of standby customers are sufficiently diverse to warrant more than one service classification. Sections six, seven, eight, and nine discuss cost allocation, the use of fixed or usage-based standby rates, reserved capacity and demand ratchets, and load diversity and generator reliability, respectively. In section ten, we explore whether standby tariffs should have availability clauses. Section eleven addresses the question of whether rates for standby service should be based on marginal or average embedded costs. Finally, in section twelve, we pose as questions issues that should be considered in any backup rate design.

Definition and Types of Standby Service

A customer that generates all or most of its electricity requirements with generation facilities located on its own premises has a need for the local utility to provide a standby service. This need arises because the availability of onsite generation is never perfect. When a customer's onsite generator becomes unavailable, due to a scheduled or unscheduled outage, the local utility must step in and use its delivery system to deliver replacement electrical energy supplied by the utility or a third-party supplier.[4] The tariffs that govern these standby delivery and energy services most often apply rates under general service tariffs modified for standby customers. However, it is becoming more common for standby rates to be based on completely separate tariffs.

There are three common types of standby service: backup, maintenance and supplemental. Backup service is electrical energy delivered by the utility during unscheduled outages of the customer's onsite generator. Maintenance service is electrical energy delivered by the utility during a scheduled outage of the onsite generator. Supplemental service is electrical energy delivered by the utility when the output of the onsite generator is less than the customer's maximum demand. In this situation, the utility will deliver all of the customer's electricity requirements beyond the level normally supplied by the onsite generator. For example, a customer whose demand is 10 MW and installs a 9 MW generator would have a supplemental load of 1 MW.

These descriptions demonstrate that the load characteristics of each service are different, resulting in different load shapes and, therefore, different service costs. Backup service, for example, is characterized by intermittent and unpredictable loads that reflect the random nature of unscheduled generator outages. In contrast, maintenance service is characterized by predictable loads associated with the scheduling of generator maintenance, usually during low cost off-peak periods. As we show later in this whitepaper, different load characteristics can cause the supplying utility to incur significantly different costs for each type of service. While it is important to take cost differences into account when designing utility rates, it is also important to recognize that there are other factors

[4] In this whitepaper, the terms "electrical energy," "electricity" and "generation" have the same meaning and cover both energy and capacity products.

that deserve consideration in the ratemaking process. These are discussed in the next section.

Principles of Utility Ratemaking

Although the load characteristics of general and standby services are very different, the principles used to design rates for these services are the same. They may be summarized as:

1. Bring in sufficient revenue to cover the utility's costs;
2. Promote the efficient use of resources used in the provision of electric services;
3. Give customers "messages" about the costs their consumption imposes on the utility;
4. Minimize discrimination among service classes and within service classes;
5. Have simple and understandable rate structures.

The first principle states that rates must bring in enough revenue to cover costs like wages, fuel, maintenance of plant and equipment, and provide adequately for depreciation and allow an opportunity to earn a reasonable return on invested capital. While this principle could be implemented by dividing the utility's revenue requirement by projected electricity sales to arrive at an average rate per kWh that would be charged to all customers, this would violate the anti-discrimination principle since it is quite obvious that it does not cost the same to serve each class of customer. This leads to the important conclusion that rates charged each customer class must reflect the costs that the class' consumption imposes on the utility.[5] If, for example, residential electric service was priced below cost

[5] The questions of whether rates should reflect average embedded costs or marginal costs and be differentiated by time of use, by season, and by voltage level are addressed briefly in a later section of this

and industrial electric service above cost, then residential customers would be encouraged to use more electricity and industrial customers less than they would if rates reflected costs. This would lead to capital being diverted to serve residential demands, while industrial demands would have to be curtailed. Such an outcome would result in an inefficient use of resources to serve electric loads. Finally, rates should be simple in order to promote understandability and public acceptance.

Before discussing in greater depth what each of the above principles means for standby rate design, we describe PSNH's current standby tariff.

PSNH's Standby Rate Design

A survey conducted by the Edison Electric Institute in the early 1990s showed that over 80 percent of all standby service tariffs billed customers on the basis of rates included in general service tariffs or modifications of general service tariffs.[6] This was the case for PSNH prior to 1992. In that year PSNH developed a new standby service tariff, Rate B, which for the first time included demand charges for transmission and distribution and generation that were different from those billed to customers taking service under the Company's general service rate schedules, namely Rate GV and Rate LG.[7] The generation demand charge was set at PSNH's marginal cost of production adjusted to take into account the standby class' expected contribution to the system peak load. The mathematical formula used by PSNH to establish the discount was based on the forced outage rates of onsite generators.[8] Finally, electrical energy purchased under Rate B

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whitepaper. Volumes have been written on the benefits of using either embedded costs or marginal costs in rate design. The issue is an important one, but is not the main focus of this whitepaper.

[6] "Standby Rates: Methods and Description", Edison Electric Institute, Rate Regulation Department, April 1991.

[7] See Order No. 20,504 in Docket DR 91-001.

[8] Order No. 20,504 does not describe the basis for the transmission and distribution demand charge.

was charged at the tail block rate of the applicable tariff, either Rate GV or Rate LG.

Today, Backup Delivery Service Rate B is fully unbundled and is mandatory for commercial and industrial customers that use onsite generation facilities to meet all or most of their electricity requirements.[9] This means that each of the three main service components – transmission, distribution and generation – is priced separately at rates specified either in Rate B or some other tariff. For example, demand charges of $3.05 and $1.02 per kW or KVA (whichever is applicable) of contract demand specified in Rate B recover, respectively, some of the allocated distribution costs and all of the transmission costs.[10] Distribution costs not recovered through demand charges are collected through energy (kWh) rates in the otherwise applicable general service tariff. Electrical energy purchased by standby customers under Rate B is billed at the energy rates in the applicable energy service tariff[11] or at rates negotiated with a third-party supplier.

The rates in Rate B are not differentiated by type of standby service and, therefore, apply to both backup and maintenance customers. Also, for a standby customer whose maximum demand exceeds the output of its onsite generator, Rate B requires that customer to take supplemental service at the rates specified in the otherwise applicable general service tariff.

[9] Rate B is optional for customers with generation installed before 1985 or whose generation is used for emergency purposes during outages on PSNH's delivery system.
[10] Rate B also includes a demand charge of $0.36 per kW or kVA of contract demand to recover stranded costs allocated to standby service; a monthly administrative charge of $189.45; a monthly translation charge of $31.07 per recorder; and a discount for $1.69 per kW or KVA of contract demand for generators who take service at 115 KV or above.
[11] Rate T or Rate DE. Note that the energy charges under Rates T and DE do not reflect seasonal or time-of-use cost differentials.

As noted above, the demand charges in Rate B apply to each of a customer's contract demand. The contract demand for a standby customer whose maximum demand exceeds the output of its generator is defined in the tariff as the normal output rating of the customer's onsite generator, even if the generator outage occurs during off-peak hours. For a customer who has a generator with a capacity greater than its maximum demand, the contract demand is based on the metered on-peak load over the previous twelve months.[12] For customers who would otherwise be served under Rate GV, the metered on-peak load is defined as the greater of: (a) the highest kW demand during the previous twelve months, or (b) 80% of the highest kVA demand during that period. For customers who would otherwise be served under Rate LG, the metered on-peak load is defined as the highest kVA demand during that twelve month period.

In short, the contract demand for a customer whose generating capacity is greater than its maximum demand is subject to a twelve month ratchet. This is in contrast to a customer whose maximum demand exceeds the capacity of its generator. Such customers are subject to fixed contract demands.[13]

Standby Service Classifications

In order to limit the number of tariffs offered to a manageable number, traditional utility ratemaking includes the creation of customer classes with similar load characteristics. Utilities typically find out about the load characteristics of their customers by operating load research programs, which produce daily load shapes for very cold and average winter days and very hot and average summer days. Customers with similar load shapes are grouped together. For most New Hampshire customers, the primary determinant of load shape is weather. This is

[12] The Seabrook Nuclear Station is such a customer.
[13] Note that if the total electrical load of such a customer increases, the increase will be treated as an increase in supplemental demand and be billed under the otherwise applicable standard delivery rate. Rate B revenues will be unaffected.

certainly true for the customer classes served under PSNH's general service tariffs and is likely true for the standby service supplemental loads served by PSNH. In contrast, the load shapes for customers taking backup and maintenance services are determined by the outage characteristics of their onsite generators.

Because unscheduled outages are independent of weather and can occur at any time, summer or winter, day or night, it is unlikely that the contribution from one kW of backup load to the summer peak demand will be the same as the contribution from one kW of air conditioning load. Maintenance outages will be even less likely to occur during the summer peak period because those outages are typically scheduled during off-peak periods. This suggests that the generation and transmission costs of providing backup and maintenance services could be different from the costs of providing service to general service loads, which would warrant a separate service classification. While this is the case for PSNH standby customers, who are served under a separate rate schedule, the transmission demand charge in Rate B is not substantially different from those in Rate GV and Rate LG. These facts raise important questions about the costing and rate design approaches underlying the transmission charges in Rate B.

During the course of the hearing in Docket DE 03-200, Wausau argued that onsite generation customers such as the Seabrook Nuclear Station place greater demands on PSNH's transmission system than do papers mills. According to Wausau, this warrants a separate standby service classification for Seabrook and associated higher rates. While we believe it is reasonable for PSNH to conduct an analysis of standby customer load shapes to permit a definitive conclusion as to whether Seabrook Station should be served under a separate classification, the available information suggests that the costs incurred in serving Seabrook may be lower on a per kW basis than the costs incurred in serving most other standby customers.

The record in DE 03-200 establishes that the Seabrook Nuclear Station is different from the rest of the standby class in terms of the magnitude of the demand placed on the PSNH system.[14] Moreover, because Seabrook maintenance outages are usually scheduled once every eighteen months, there is some certainty to the need for maintenance service. It is also true that the durations of maintenance outages are long enough that even if such outages are scheduled during off-peak months, the station has a high probability of contributing to one of the utility's monthly system peaks.

On the other hand, given the scheduling of maintenance outages during off-peak months and the relatively low incidence of unscheduled outages for most well managed nuclear power plants, the probability that standby service would be needed during the summer on a summer peaking system like that of PSNH seems low. Even if transmission costs are driven more by monthly peak demands than by the annual peak demand, it is quite possible that other standby customers request service with greater frequency than Seabrook and thus are more likely to be contributing to those monthly peaks than Seabrook.[15]

It is also possible that the non-Seabrook standby customers require PSNH to purchase power during high cost periods, thus raising the cost of transition service. While the primary focus of Docket DE 03-200 was on the allocation of transmission and distribution costs among rate classes and between standby customers, it should not be assumed that the current energy rate design is

[14] See Order No. 24,369, DE 03-200, page 18.
[15] Seabrook's responsibility for distribution costs will depend on the specifics of the method used by PSNH to allocate those costs.

efficient. We believe there is a need for a more informed discussion on whether the generation rates for Rate B service should better reflect seasonal and time-of-day cost variations.[16]

The above comments suggest that any determination as to the reasonableness of the Rate B rate structure as it applies to different standby customers will require the collection of load shape data for all customers in the class and a better understanding of how costs are incurred on the PSNH system. Without that information, it would be difficult to determine whether Seabrook or any other customer should receive separate rate treatment.

Cost Allocation

The most contentious issue in Docket DE 03-200 was how to determine Rate B's allocated share of transmission cost. While PSNH had proposed to assign transmission costs to standby customers based on the sum of the contract demands of Rate B customers, the Rate Design Settlement approved by the Commission adopted a proposal submitted by the Staff. The essence of the staff proposal was FERC rule 18 CFR 292.305 subsection (c) (1), which states that the standby service rates "[s]hall not be based upon an assumption (unless supported by factual data) that forced outages or other reductions in electric output by all qualifying facilities on an electric utility's system will occur simultaneously, or during the system peak, or both."

In effect, the PSNH proposal, which runs counter to the above mentioned rule, assumes that all standby customers would not only request backup or maintenance service at the same time but would do so during the summer peak period. This assumption is not realistic. Given the random nature of generator

[16] One way to achieve this goal is to require standby customers to pay real time spot market prices, i.e. the zonal LMP.

outages, few customers would be off-line simultaneously and even fewer of those customers would be off-line during the summer peak. While the staff proposal was accepted by the settling parties as a reasonable resolution of the cost allocation issue in that preceding, we recognize that there may be other ways to solve this allocation problem.[17]

Fixed or Usage-Based Standby Rates

Most costs associated with the provision of transmission and distribution services to onsite generation customers are fixed. Thus, recovering these costs through fixed reservation charges, also referred to as contract demand charges, would appear to be consistent with providing accurate price signals to customers. Some standby customers, however, contend that the use of fixed reservation charges to recover transmission and distribution costs will deter the use of onsite generation, even when such use would be economically efficient.[18] Accordingly, these customers recommend usage-based, volumetric charges. The same customers also point out that the use of fixed reservation charges to recover standby service costs is inconsistent with the design of general service rates, which typically comprise fixed and volumetric charges.

Since most onsite generation facilities are designed to run continually, meaning only a small fraction of the customer's electricity requirements will be supplied by the utility, usage-based volumetric charges may result in the under-collection of fixed costs and, as a result, the uneconomic bypass of the utility system. Since this would increase the cost burden on other customers, we believe that the use of fixed reservation charges to collect most costs is appropriate. However, see

[17] See"Standby Rates: Methods and Description", Edison Electric Institute, Rate Regulation Department, April 1991

[18] See, for example, the Interim Decision Adopting Standby Rate Design Policies issues by the California PUC in Rulemaking Docket 99-10-025, July 12, 2001.

below under reservation charges for a discussion on the recovery of costs incurred to provide maintenance service.

Load Diversity and Generator Reliability

Standby customers often argue that charges for standby service should reflect the diversity[19] among standby customer loads and the reliability of the onsite generators. Regarding the first factor, since not all onsite generators will require backup service at the same time, it seems reasonable to conclude that diversity exists and should be taken into account when determining the costs of standby service. Utilities typically respond by distinguishing between transmission and distribution diversity. While diversity may exist at the transmission level, they argue that because of the radial design of distribution systems and the relatively small number of generators connected at distribution voltages, there is virtually no diversity on individual distribution circuits. If this is correct, utilities would have to plan to serve effectively all standby load on a circuit in the event of a circuit outage. This may be the case with PSNH, which serves relatively few standby customers, but the actual amount of diversity at transmission and distribution levels should be quantified. Proposed diversity factors should be accompanied by numerical support.

Regarding the second factor, it is often argued that reliable generators place less demand on a utility's system than do unreliable generators. This explains why the rates for standby service are sometimes expressed as the product of a demand charge and an estimated forced outage rate for onsite generators. The rationale for this argument is as follows: a generator that is always unavailable will require the utility to provide standby service at all times including during the

[19] Diversity is defined as the ratio of the sum of the individual customer maximum demands on a circuit to the actual maximum demand on the circuit.

peak hours. Thus, such a generator would be billed the full demand charge. In contrast, a generator that is always available will never request utility service and, hence, would pay nothing. The typical response to this argument is that costs incurred to construct facilities that enable utilities to stand ready to serve standby customers are the same regardless of whether the customers use those facilities one time each year or a hundred times a year.

Reserve Capacity, Reservation Fees, and Monetary Penalties

As noted above, backup and maintenance delivery services are distinguishable by the fact that backup loads are random and unpredictable whereas maintenance loads are predictable. Thus, utilities offering backup service are required to reserve distribution, transmission and generation capacity at all times in order to ensure that backup loads are fully met. This suggests that customers requesting backup service should be required to contract for it in advance and pay a reservation charge that recovers the associated backup service costs.[20] This is the rate structure employed by PSNH in Rate B.

Further, if a customer's demand for backup service exceeds its reserve level in any billing month, it is common to require that customer to pay a monetary penalty on the excess demand. More often than not, this penalty is implemented by adjusting upward the customer's reservation capacity for a specified future term. Tariff provisions that allow the reservation capacity to be re-set in the event of a change in demand are known as demand ratchets and are common features in general service tariffs for large commercial and industrial customers.

[20] The reserved capacity and associated reservation charge should exclude the standby capacity needed to supply supplemental service. Supplemental service costs are recovered through the rates included in the applicable general service tariff.

In contrast to backup service, maintenance service is generally scheduled by the customer at times of low demand and therefore should not require the utility to build or reserve capacity to serve it. Thus, maintenance service is likely to be significantly less costly than backup service and should not require a reservation charge or demand ratchet to collect the costs. This raises the question of whether the provision of maintenance service incurs only variable costs, which would be recovered through a usage-based rate.

The design of the demand ratchet in Rate B was raised by the parties in DE 03-200 in the context of standby service to the Seabrook Station which, as noted above, was alleged to be considerably more costly to serve than other standby customers. Because the Seabrook Station operates on an eighteen month re-fueling cycle, the unit will be off-line for refueling and maintenance in two of any three consecutive years. Accordingly, if the test year for a PSNH base rate case corresponds to a year in which the unit is not off-line for scheduled refueling and maintenance, the total standby class demand in that year could understate the average annual demand, potentially resulting in a lower allocation of transmission and distribution costs to standby customers. On the other hand, if the test year corresponds to a year in which the unit is off-line for scheduled refueling and maintenance, standby customers could potentially receive a higher allocation of transmission and distribution costs.[21] This potential increase in costs allocated to the standby class should not, however, be a concern to the non-Seabrook standby customers provided the billing determinants used by PSNH to calculate the transmission and distribution demand charges reflect actual test year billing demands. Assuming demand charges are calculated correctly, PSNH will then

[21] The costs actually allocated to standby customers will depend, of course, on the methods used by PSNH to allocate transmission and distribution costs. For example, if transmission costs are allocated on the basis of each rate class' contribution to the system peak demand in the test year, the fact that nuclear plant refueling outages are typically scheduled during off-peak months could reduce rather than increase the total costs allocated to the class. Further, if the allocated costs are recovered from customers based on non-coincident demands (as is the case in Rate B), the reduction in costs may flow disproportionately to the non-nuclear customers.

attempt to recover the allocated costs by applying the approved demand charges to the billing demands for each standby customer. However, because the Seabrook Station billing demand is currently subject to a twelve month ratchet, PSNH's billings to Seabrook will change depending on whether the unit was or was not off-line at any time during the preceding eleven months. While changing the term of the ratchet from twelve to eighteen months would smooth PSNH's revenue stream and eliminate the temporary reduction in charges that Seabrook realizes under the current tariff, it is unclear without further investigation whether such a change would be in the interests of other customers.[22] For example, it would appear that customers with large generators that experience infrequent outages could be harmed by such a change.

Generation Plant Availability Clauses

In the debate over what constitutes an acceptable rate design for Rate B, the issue of the availability of onsite generators was raised. That is, should the ability of a customer to take service under a standby service tariff or general service tariff be tied to the availability of that customer's standby generator. For example, Atlantic City Electric Company in its standby service tariff, i.e. Rider-STB, requires customers with other sources of electrical energy to have a 50 percent generation availability over the current and previous 5 months to remain eligible for standby service.[23]

An availability requirement like the one required by Atlantic City essentially precludes customers with generation facilities from obtaining standby service if

[22] It is important to note that if the Seabrook Station is on-line throughout the test year resulting in a lower allocation to the standby class, the current design of the ratchet results in Seabrook being over charged relative to the allocated costs. Further, changing to an eighteen month ratchet would increase the over collection.

[23] See "Atlanic Electric Tariff for Electric Service, Section IV-Service Classifications and Riders", Page 44-45, http://www.conectiv.com/cpd/tariffs/electric/newjersey/nj_tariff_IV.pdf

their usage characteristics under that service are similar to the characteristics of customers taking standard delivery service. While such an availability requirement is useful in ensuring that customers receive the service that best fits their needs, it is also important to recognize that customers with generation facilities that do not qualify for standby service based on the availability criterion can nonetheless cut their energy costs by utilizing those facilities in conjunction with interruptible service to supply their electricity requirements. For these reasons, we support the inclusion of an availability clause in Rate B.

Embedded or Incremental Cost-Based Standby Charges

There are also differing views on whether the standby rates should reflect embedded or marginal costs. Proponents of embedded cost based rates generally argue that a standby charge that reflects the marginal costs of providing distribution, transmission and generation services to onsite generators must be reconciled to the standby class revenue requirement in order to avoid the under recovery of embedded costs. The same entities also argue that the rates for standby service should reflect embedded costs, particularly if the charges for all other retail service classifications reflect embedded cost. Proponents of embedded cost-based rates also tend to be opposed to standby rates that reflect geographic distinctions, on the grounds that averaging utility rates across a service territory fairly spreads the costs of system improvements to all customers. However, marginal cost based pricing, including localized transmission and distribution rates, send more efficient price signals and are the costs planners use when making investment decisions.

Issues for Consideration

The following are some of the issues raised by the whitepaper.

a. Are the characteristics of maintenance service sufficiently different from backup service to warrant separate pricing? Is it reasonable, for example, to assume that maintenance service will always be scheduled during off-peak periods thus reducing the need for transmission and distribution upgrades to serve the associated load?

b. Should customers taking maintenance service be billed based on a usage-based rate that recovers proportionately less transmission and distribution costs?

c. Should standby demand charges be based on average embedded, not marginal, costs, consistent with the way demand charges are calculated for general service classifications?

d. Should energy purchased from a utility by customers taking backup and maintenance services be billed at a different rate than that billed to supplemental service customers? If so, what is an appropriate structure for the differential?

e. Should energy charges for backup and maintenance service be tied to real time zonal LMPs?

f. Should more of the costs incurred in providing standby services be recovered through usage-based charges? If so, what method should be used to determine which costs are fixed and which are variable?

g. Should the number of standby service classifications be increased? If so, is it appropriate to do so without first conducting an investigation of individual customer load shapes?

h. Should the ratchet provision in Rate B be revised? For example, would it be appropriate to increase the term of the ratchet from twelve to eighteen months to accommodate the refueling of Seabrook?

i. Are the allocation methods used to allocate transmission and distribution system costs among customer classes reasonable? That is, do they reflect cost causation?

j. Are the methods used to calculate transmission and distribution demand charges for standby customers supported by sound costing and rate design principles?

k. What is an appropriate methodology for determining the standby service class' distribution cost responsibility?

l. Is it reasonable to assume that diversity exists at transmission level voltages? If so, what is an appropriate diversity factor?

m. Is it reasonable to assume that diversity does not currently exist at distribution level voltages?

n. What is the likelihood that multiple onsite generators will be out of service on the same distribution circuit simultaneously?

o. Should standby service tariffs include an availability clause and, if so, how should the clause be structured?

p. PSNH's current standby tariff already includes a discount for customers interconnected at 115 kV or above in recognition of the costs saved in delivering power at higher voltages. Is the size of the discount reasonable and should other cost savings be reflected in the tariff?

q. What are the delivery system benefits associated with customer owned onsite generation and how should they be reflected in standby service rates? Do these benefits vary by generator fuel type and size?